INCREASE MTBF BY PUMPING THE CURVE WITH THERMOPLASTIC LINERS

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Rod pumping unconventional wells can be challenging due to increased side loading conditions thru the curve section of the wellbore. Likewise, 'S' shaped wells and unintentional dog legs present a similar problem with increased failure rates. All of these conditions lead to higher side loading resulting in increased friction and wear and a corresponding decrease in Mean Time Between Failures (MTBF). This phenomenon can make lifting fluids with rod pumps problematic due to extreme deviations and the resulting forces.

As production and bottom hole pressures decline, many wells will be converted to rod pump at some point in their lives. Rod pumping is usually the preferred artificial lift method for lower gas to liquid ratio (GLR) wells with low or declining bottom hole pressure. When unconventional wells are converted to rod pump, they usually start out with the pump set above the kick-off point. However, as production declines, the operator may need to lower the pump to maintain economical production rates and maximize hydrocarbon recovery. To achieve these goals, operators have pumped the curve with varying levels of success. Historically, when lowering the pump into the curve, failure rates increase due to increased mechanical friction on the downhole equipment. Tubing leaks, rod parts and pump failures are the most common failure types for these applications.

When pumping through the curve, rod guides are often installed on sucker rods below kick off point as they provide a sacrificial wear devise that attempts to protect the tubing and rods. Unfortunately, rod guides increase the amount of friction in the system.

Thermoplastic liners, which are mechanically bonded to new or used tubing, significantly increase run time by preventing rod on tubing contact. Installing thermoplastic liners below kick off point can decrease failure rates by reducing the downhole mechanical friction.

The effects of different corrective measures to deviation and their respective coefficients of friction are detailed and discussed in this paper.

This paper presents results from a case study where thermoplastic liners were installed on high failure rate ESP wells that were converted to rod pump and provides evidence that pumping the curve can be an economical and feasible option for operators when designed properly.

INTRODUCTION

Rod pumping unconventional wells can be challenging due to increased side loading conditions thru the curve section of the wellbore. 'S' shaped wells and unintentional dog legs present a similar problem with increased failure rates. All of these conditions lead to higher side loading resulting in increased friction and wear and a corresponding decrease in Mean Time Between Failures (MTBF).

Unconventional wells are generally drilled "vertical" and then "kicked-off", building the curve and then continuing to drill horizontally at a targeted distance through the payzone. When horizontal wells, or any wells with significant dog legs, are rod pumped in or through a deviated section of the wellbore, mechanical friction is created between the rods and the tubing leading to rod parts and tubing failures.

After wells begin to decline, the typical unconventional well will need to be artificially lifted at some point in order to maintain targeted production rates. Rod lifting these unconventional wells has proven to be a challenge due to deviation, gas interference, varying gas-oil ratios and fluctuating production rates, see [6]. When it is no longer economical to lift the well from above kick-off point, operators may lower the sucker rod pumps into the curve or lateral portion of the well to reduce producing bottomhole pressure on the reservoir.

Historically, when lowering the pump into the curve, failure rates increase due to increased mechanical friction on the downhole equipment. Tubing leaks, rod parts and pump failures are the most common failure types for these applications.

ADVANTAGES AND CHALLENGES OF PUMPING THE CURVE

The most common lift methods installed on unconventional wells include gas lift, electric submersible pumps (ESPs), and rod pump. Gas lift works well for high GLR and/or high-rate wells but as flowing bottom hole pressures decrease, its advantages quickly diminish. Lack of compression facilities also reduces gas lift feasibility.

Electric submersible pumps (ESPs) work well if the GLR is moderate and fluid production is above minimal volumes. Similar to gas lift, ESPs become less attractive at low producing BHPs as the pumps have a tendency to gas-lock at lower rates and/or begin to overheat due to a lack of fluid necessary to cool the motor. As bottomhole pressures decline, continued use of ESPs becomes difficult to justify due to high operating and repair costs. Also, ESPs may not be ideal later in life due to the steep decline curve of horizontal wells. As per the case study presented below, several wells were converted from ESP to rod pump due to a drop in production and repeated ESP failures.

For the above reasons, conventional sucker rod artificial lift is often the most viable and effective option due to its versatility and availability despite its more modest production volumes. Rod pumps are less sensitive than gas lift and ESP to varying production rates.

Traditionally, in unconventional horizontal wells, operators position the pump in the vertical section of the wellbore. When producing from above the producing intervals without a method of gas separation, gas bubbles are entrained in the fluid. This reduces the volumetric efficiency of the pump and is a function of the pump intake pressure, which dictates the size of the gas bubbles. When pump intake pressure is high, gas bubbles are small and gas interference can be manageable due to the gas being entrained in the fluid. When pump intake pressure decreases, the size of the gas bubbles increase, and more volume is occupied by gas inside the pump. Special care should be taken to determine the best method to reduce the gas interference effect for these wells to increase pump efficiency and increase production.

When wells begin pumping off, i.e. the pumping rate exceeds the amount of fluids inflowing from the reservoir. At that point the pump intake pressure (PIP) drops, and gas interference increases, contributing to the production decline unless adjustments are made.

In horizontal wells, operators are generally not able to reduce producing bottomhole pressure as low as a traditional vertical well. This is due in part to the excess hydrostatic pressure exerted by the fluid column in the deviated and horizontal sections of the wellbore. As wells continue to decline, the available producing bottomhole pressure is insufficient to push liquid and gas up to the pump located in the vertical section from the formation at an optimal rate. Landing the pump in the curve section or the horizontal section of the wellbore can allow operators to reach lower producing bottom hole pressures, increasing production and potentially extending the life of the well.

In most wells, pumping the lateral portion of the hole can increase drawdown by several hundred psi resulting in higher production rates. However, failure rates when pumping below the kick-off point can be two or more times higher than pumping in the vertical section. Mechanical friction and the resulting tubing and rod wear in the deviated section of the well is the main cause of failures. Pump failures remain the predominant issue, but rod failures and tubing failures also dramatically increase as discussed in [6].

The traditional solution to mitigate friction wear is by using rod guides. Rod guides are used in a sacrificial fashion to prevent rod on tubing contact. Rod guides increase the amount of friction in the system. While the coefficient of friction for steel-on-steel contact is 0.2, the coefficient of rod guides-on-steel is between 0.25 and 0.3 depending on the material. This will increase gearbox and structure loading, therefore increasing surface equipment requirements.

Another solution to pumping the curve is installing continuous rod. Continuous rod is designed to disperse side loads along the length of the rod creating a larger area of contact for the rod on tubing side loads, as seen in [2]. The decrease in mechanical wear between the rods and tubing with continuous rod is because conventional rods contact the tubing along the length of the coupling alone, due to the greater outside diameter difference between the sucker rod body and the couplings, see [10].

In contrast to rod guides, thermoplastic liners have a lower coefficient of friction at 0.1, which greatly reduces drag forces and mechanical friction. This has been proven by comparing predicted loads to actual loads measured in the field. Reducing friction will reduce gearbox load and overall surface requirements, while at the same time increasing production. Thermoplastic liners dramatically reduce rod/pump on tubing wear, which is a major cause for failures in deviated or horizontal wells.

<u>CONTINUOUS ROD</u>

The weakest links of a conventional rod string is the connections. The connections are responsible for many of the downhole rod failures such as fatigue breaks, erosion from constant contact with the tubing, and loosening of the connections from fluid pound or improper makeup. Continuous rod has only two connections and essentially eliminates the above-mentioned problems.

Continuous rod is well suited for deviated wells as rod guides are not needed in an attempt to minimize the wear created by rod/tubing contact. Furthermore, because continuous rod is slightly lighter than a conventional rod string due to the lack of couplings, the magnitude of the side load incurred will be slightly reduced. Also, in a conventional rod string, the restriction in area imposed by the coupling may create turbulent flow, resulting in fluid friction losses. In continuous rods, these losses are eliminated, see [3, 4].

As mentioned above, when using continuous rod, less mechanical friction is created than when using rod guides to mitigate issues caused by deviation. This is due to the lower coefficient of friction of steel-on-steel compared to rod guides-on-steel. As explained in [9], mechanical friction results in a shorter downhole stroke, resulting in less production at the same pumping speed. Therefore, installing continuous rod improves failures rates with less wear and increases production with a longer downhole stroke.

As stated above, one of the advantages of continuous rod is improved performance in deviated wells where mechanical friction between the rod and the tubing strings leads to early failures. Continuous rods are designed to disperse side loads along the length of the rod creating a larger area of contact for the rod on tubing side loads, as described in [1] and displayed in Figure 1.

Abrasive wear is defined as “wear in which hard asperities on one body penetrate the surface of a softer body and ‘dig’ material from the softer surface, leaving a depression or groove”, cf. [2]. Continuous rod will abrade the tubing distributed along the entire length of contact as opposed to a concentrated force acting on the couplings, cf. [1].

In the case of a conventional rod string, because the coupling has a larger diameter than the rod body, the contact force is concentrated on the couplings, following the concept of a centralized force or pinch point. In the case of continuous rod, because there are no couplings, the contact force is spread out over the entire area of the surface contact area of the continuous rod string. Because the force is spread over a greater area, the pressure the force applies is less per unit area. This results in significantly less wear. A diagram showing the difference in the contact areas of a conventional rod string versus a continuous rod is represented in Figure 1.

Also, continuous rod provides a greater cross-sectional area for fluid flow. An advantage to continuous rod is a slight increase in production as the clearance between the tubing and the rod is increased. This results in unrestricted flow through a larger surface area.

Additionally, the absence of couplings in continuous rod eliminates the creation of turbulent flow. With low viscosity fluids, in parts of the rod string where the rod velocity is the largest, turbulent flow is induced, see [7]. The turbulent flow is created from the couplings and/or the molded guides distributed along the rod string.

The use of continuous rod reduces failures with the lack of couplings and rod guides, reducing friction due to the lower coefficient of friction and distributing the side load. Because continuous rod is connectionless, it eliminates turbulent flow, reducing fluid friction and increasing the flow area. The lower friction in the system results can result in lower loads at surface. More details on the benefits of continuous rod can be found in [8].

THERMOPLASTIC LINERS

Lined tubing is a thermoplastic liner that is extruded into the shape of a pipe or tubing profile and is mechanically bonded to the tubing string.

No Direct Contact with Tubing – Alleviating Downhole Wear:

Downhole wear, caused by the mechanical friction between rods and tubing, can cause costly and frequent workovers. This wear is enhanced when the pump is set below kick-off point. A common solution that operators may use to prevent downhole wear are rod guides. Rod guides add friction to the system, causing higher loads on the rod string and the surface equipment. Rod guides also create a flow restriction in the tubing, leading to turbulent flow around the guides. Corrosive elements are more likely to break out from the fluid in these turbulent flow areas, leading to corrosion pitting near the end of a guide.

Thermoplastic liners prevent steel-on-steel contact and minimize the rod friction that creates tubing wear. The liner acts as a barrier between the rod string and the tubing string. This will significantly increase mean time between failures. The proper resin for a well with mechanical friction issues will depend on the BHT, side loads, and dogleg severity. Typically, a crystalline resin should be used in the case of high side loads (depending on various other factors as well i.e. corrosion, downhole temperature). Crystalline resins are denser, so they will wear slower than an amorphous resin like HDPE.

Protects Against Corrosion:

There are several practices that operators may use to mitigate downhole corrosion including a chemical treatment program, altering the metallurgy of the steel, or using tubing with internal plastic coatings. Installing lined tubing to protect against downhole corrosion has become a common practice. The best resin for a well with corrosion issues will depend on the types and amounts of corrosion downhole (among other factors i.e., downhole temperature). Crystalline resins can handle higher amounts of corrosion than an amorphous resin like HDPE.

Lower Coefficient of Friction:

The friction coefficient for steel-on-steel contact is 0.2, while the friction coefficient for most rod guides-on-steel is between 0.25 and 0.3. Rod guides are used in a sacrificial fashion to absorb the wear between the conventional rod/couplings and tubing. Rod guides increase the gearbox, structure, and rod loading by adding extra friction into the system. This can require larger surface equipment and higher strength rods.

In contrast, thermoplastic liners have a friction coefficient of 0.1, which reduces the friction forces in the rod pumped system. This will reduce wear and tear on the downhole equipment. The loads on the rod string will be lighter due to lower friction, increasing the fatigue life of the rod string.

To illustrate the effect of having a lower coefficient of friction, Table 1 displays the difference in gearbox loading, PPRL, MPRL, polished rod horsepower, maximum rod stress, maximum side load and downhole stroke for conventional rods, continuous rods, conventional rods with TPL, continuous rod with TPL and conventional rod with rod guides.

A predictive design program was used to generate results presented in Table 1 using data from case study Well #1. Different cases were run using the same well data to show the differences between using bare conventional rods, conventional rods with TPL, conventional rods with rod guides, bare continuous rod, and continuous rod with TPL producing the same amount of fluid.

As can be seen from Table 1, thermoplastic liners reduce the gearbox loading. When comparing bare conventional rods to conventional rods with rod guides, the gearbox loading increases from 110% to 119%. Continuous rod on bare tubing equates to a gearbox loading of 101%. Adding TPL to a conventional rod pumped system, the gearbox loading decreases to 90% and when adding TPL to a continuous rod pumped system, gearbox loading decreases from 101% to 83%.

The PPRL values follow a similar trend. The PPRL values when installing TPL are significantly less than the cases without TPL. It should be noted that the PPRL values when using continuous rod and bare tubing are comparable to using conventional rods with TPL.

Polished rod horsepower is the amount of energy required at the surface to lift the fluids. In the case of conventional rods with rod guides, the polished rod horsepower requirement is 49.4 HP as the system must compensate for the extra friction created by the guides. Polished rod horsepower for the bare conventional rod case and bare continuous rod case are 42.4 HP and 40.3 HP, respectively. It should be noted that when installing thermoplastic liners, the polished rod horsepower decreases by approximately 10 HP to 31 and 30 for conventional rods with TPL and continuous rod with TPL, respectively.

Similarly, installing TPL lowers the maximum rod stress from 106% to 92% for conventional rods with bare tubing and from 84.2% to 73.6% for bare continuous rod to continuous rod with TPL. By decreasing the rod loading, the fatigue life of the rod string increases.

The side load that is computed in the predictive program is a representation of the intensity of the contact force at a particular depth. Side load is proportional to the peak polished rod load and relates to dog leg severity. Side load is also related to wear. From Table 1, thermoplastic liners reduce maximum side load from 664 lb/25ft to 595 lb/25ft when comparing conventional rods with bare tubing to conventional rods with TPL. When comparing continuous rod with bare tubing and continuous rod with TPL, the resulting side loads are 581 lb/ft and 532 lb/ft respectively. With rod guides, the computed side load equates to 705 lb/25ft.

Fluid production is primarily dictated by the downhole stroke length. The greater the downhole stroke, the more fluid the pumping system can produce. As can be seen in Table 1, when comparing conventional rods with bare tubing and conventional rods with TPL, using TPL increases the downhole stroke from 176.1 inches to 188.4 inches. When comparing continuous rod with bare tubing and continuous rod with TPL, the downhole stroke increases from 178.1 inches to 185.9 inches.

From Table 1, it can be concluded that the using TPL reduces surface requirements and stress on the equipment. Using TPL also increases production by increasing the downhole stroke. TPL generates the above benefits due to the reduction in friction.

The equation for the normal force is given by:

$$F_N = L_r \cdot W_r (1 - 0.127 \cdot \gamma_F) \sin \alpha . \qquad (1)$$

Where F_N is the normal force (lbf), L_r is the length of the rod string (ft), W_r is the weight of the rod string (lb/ft), γ_F is the fluid specific gravity and α is the inclination (degrees). The normal force is proportional to the weight of the rod, therefore, the lighter the rod the smaller the normal force will be.

The equation for drag is given by:

$$F_D = -f_{friction} \cdot |F_N|. \qquad (2)$$

Where $f_{friction}$ is the friction coefficient between the rods and tubing or rods and TPL. The magnitude of the drag force in lbf, F_D, is proportional to the normal force and acts in the direction opposite to the movement of the rod string.

Table 2 shows the normal force calculation and resulting drag force looking at depth 6644ft for below case study Well #1 where inclination angle is 48.43° and azimuth angle is 180.96° resulting in a DLS of 15.26°/100ft, which is the highest DLS for the horizontal segment of the well. Thermoplastic liner was installed from 5,925.9 ft to 7,100.4 ft. The length of rods below the bend and until pump depth is 421ft. As mentioned above the coefficient of friction for steel-on-steel contact is 0.2, rod guides- on-steel is 0.25, and thermoplastic liners is 0.1. The below cases were run with .875-inch conventional and continuous rod, as Revolution Resources ran .875-inch rod below kick-off point.

As can be seen in Table 2, the difference in drag force on conventional rods with bare tubing compared to conventional rods with TPL is significant. The drag force is reduced in half from -7.26 lbf to -3.63 lbf. The reduction in drag force is greater when comparing conventional rods with TPL to conventional rods with rod guides. The drag force is reduced from -9.08 lbf to -3.63 lbf. Similarly, with continuous rod, using TPL reduces the drag force from -6.66 lbf to -3.33 lbf.

Installing thermoplastic liners in lateral applications allows operators to decrease producing bottomhole pressure without increasing failure rates. Thermoplastic liners also decreased OPEX due to the reduction in friction and failures. The reduction in failure rates, power savings, and potential reduction in surface requirements, makes thermoplastic liners an economic solution to pumping the curve of unconventional wells.

RESULTS: CASE STUDY WITH REVOLUTION RESOURCES

Thermoplastic liners were installed in Revolution Resources' West Edmond Hunton Lime Unit Field near Deer Creek, Oklahoma. The wells are being converted from ESP to rod pump as fluid rates decline or if a significant number of ESP failures have occurred. Revolution Resources took over operations in the field at the beginning of 2018.

The previous operator began drilling horizontals in this unit dating back to 2005 with over 80 horizontal wells drilled to date. The producing reservoir is known to have very low bottom hole pressure. Initial bottom hole pressures range anywhere from 200 to 500 psi. The low BHP makes lifting the well above the kickoff point economically unattractive. Newly drilled wells are initially lifted with an ESP set below the kick-off point and then converted to rod pump.

Figure 2 shows a typical bottom hole assembly for this case study detailing placement of lined tubing, pump seating nipple, perforated sub, and mud anchor.

As mentioned above, due to low bottom hole pressure, it is necessary to produce these wells below the kickoff point from the onset. Tangents measuring 200 feet are drilled anywhere from 75-90° inclination to successfully produce the ESPs.

As production decreases below 200 bfpd or if a significant number of ESP failures occur, the wells are converted from ESP to rod pump.

However, when converting to rod pump, the friction created between the rods and the tubing through the curve, make it difficult to pump these wells efficiently. After modeling different rod designs and many field trials, it was concluded that installing thermoplastic liners through the curve is the most efficient method of pumping below the kickoff point.

The assembly is representative of the following case study examples.

Well # 1:

The first well in this study has the pump set at 7,135 feet with a rod string taper consisting of 2,735 feet of 1-1/4 inch fiberglass rods, 1,550 feet of 1 inch steel sucker rods, 1,050’ 7/8 inch steel sucker rods, 750 feet of 1.5 inch sinker bars, and 7/8 inch steel sucker rods beneath the kickoff point and throughout the curve. This well was installed with a 1.75 inch insert pump. Thermoplastic liners measuring 1,174 feet in total length were installed below the kick-off point between 5,925 feet and 7,100 feet.

Table 3 shows the deviation survey data for the section of well where the pump was set at 7,135 feet.

Figure 3 displays the deviation survey for Well #1 with blue representing the bare tubing sections and yellow representing the lined tubing section. As can be seen by Figure 3, thermoplastic liner was installed slightly above the kickoff point and continued into the lateral section of the wellbore.

When converting from ESP to rod pump, thermoplastic liners were installed in the curve section of the wellbore to prevent rod and coupling wear on the tubing. Another option is to use rod guides, which increases the friction in the overall system by absorbing the contact between the tubing and the rods. Revolution Resources reported issues with increased friction and surface requirements, as well as higher failure rates when utilizing rod guides throughout the curve on similar wells in the West Edmond Field.

To quantify the difference between using thermoplastic liner as opposed to rod guides, two cases were calculated using a predictive program to contrast the difference in performance of the two solutions for these case study examples. Results from the comparison for Well #1 are displayed in Table 4.

As can be seen from Table 4, using thermoplastic liners in contrast to rod guides at similar pumping speeds, decreases the peak polished rod load and increases the minimum polished rod load. When friction is present, it can cause a shorter downhole stroke. This means less production or increasing the strokes per minute to meet targeted production. In this case, using thermoplastic liners instead of rod guides increases the downhole stroke by 18.5 inches from 139.3 to 157.8 (13% increase). The peak polished rod load (PPRL) decreased from 33,025 to 31,235 lbs and the minimum polished rod load increased from 5,218 to 5,859 lbs. Decreased PPRL and range of polished rod load benefits the power and efficiency requirements of the rod pumped system at the surface. The gearbox loading, which is overloaded in the case with rod guides at 110.7% decreases to a more acceptable operational range of 93.3% with thermoplastic liners. This is a 16% difference reduction in gearbox loading. In this case, installing thermoplastic liners instead of rod guides removes the risk of overloading the gearbox and improves operation of the system. The overall pumping unit loading decreases from 77 to 73 percent. Shifting from rod guides to thermoplastic liners also reduces the monthly electric cost by an estimated $261 and decreases peak rod loading from 80% to 74%. A difference in production is also anticipated though not apparent through the predictive program calculations.

Using inferred production equation from [9] which reads:

$$PD = 0.1166 \cdot d^2 \cdot S_p \cdot SPM * \mathcal{E}_p. \tag{5}$$

Where PD is the inferred production in bpd, S_p is the downhole plunger stroke, d is the plunger size in inches, $\mathcal{E}_p$ is the pump volume efficiency, and SPM is the pumping speed in strokes/minute. The pump inner diameter for the plunger in Well #1 is 1.75 inches. The pump volume efficiency used in all cases below is 85%. Using equation (5), production with rod guides is 248 bpd, while production with TPL is 281 bpd.

After converting this well from ESP to rod pump with thermoplastic liners throughout the curve, Revolution Resources analyzed a dynamometer card to compare the actual load on the system compared to the predictive program. As shown in Figure 4, the actual results of the PPRL at 31,542 lbs is close to the predicted PPRL of 31,235 lbs.

Figure 5 shows the production trends before and after conversion from ESP to rod pump with thermoplastic liners throughout the curve.

As mentioned above, ESP wells were converted to rod lift when the production dropped below 200 bbls of fluid per day, however in some cases it was necessary to convert them earlier due to numerous ESP failures, as is the case of Well #1.

Two factors should be considered here, the steep production decline of the well and the conversion from ESP to rod pump. One would expect a drop in production when switching artificial lift methods along with a declined production curve to match the decline of the reservoir. In Figure 5, a decline in production can be seen after conversion to rod pump but appears to be more in relation to the natural decline state of the reservoir than due to the conversion to rod pump. It can be inferred from Figure 5 that for Well #1, the production decline matched before and after converting from ESP to rod pump.

Converting this well to rod pump with thermoplastic liners in the curve has drastically reduced the failure rate. The well has not failed to date since converting 16 months ago. Net operating revenue was nearly doubled by decreasing failure rates.

The previous failure rate for Well # 1 prior to rod pump was 3 failures in 8 months or 4.5 failures per year. After conversion to rod pump with thermoplastic liners in the curve, there has been zero failures. The well has a current run time of over a year. The average cost of an ESP failure for this operator is $60,000, therefore Revolution Resources has saved approximately $348,000 since install.

Figure 6 illustrates the monthly electrical cost decrease after converting from ESP to rod pump. To accurately model the savings shown, the electric costs are broken down in dollars per BOE. Revolution Resources saved $2 per BOE after converting to rod pump compared to ESPs due to the overall efficiency of the system.

Well #2:

The second well in this study has the pump set at 7,230 feet with a rod string taper consisting of 2,180 feet of 1-1/4-inch fiberglass rods, 2,100 feet of 1 inch steel sucker rods, 2,100 feet of 7/8 inch steel sucker rods, and 850 feet of 1 inch steel sucker rods. This well has a 1.5 inch insert pump. Thermoplastic liner measuring 2,331 feet in length was installed from 4,900 feet to 7,230 feet.

Figure 7 displays the deviation survey for Well #2 with blue representing the bare tubing sections and yellow representing the lined tubing section. As can be seen by Figure 7, thermoplastic liner was installed below the kick of point and continued into the lateral section of the wellbore. The kickoff point was near 4,800 feet for this well, but it should have been around 6,300 feet in this field. This well was drilled by the previous operator so the reason for why the well was kicked off at a shallower depth is unknown.

To quantify the difference between using thermoplastic liner as opposed to rod guides, two cases were calculated using a predictive program. Results from this comparison are displayed in Table 5.

Similar conclusions can be drawn as seen in the two cases run with Well #1 data above.

Figure 8 displays the production data for Well #2. Like Well #1, this well experienced multiple ESP failures before conversion. After conversion, oil and water production was maintained, while gas production increased due to not having to fight the ESP constantly gas locking. Converting to rod pump reduced the failure rate from 2 failures per year to zero failures in 11.5 months. This results in approximately $120,000 in savings. For this well, like Well #1, net operating costs were greatly increased with minimal production losses.

Well #3:

The third well in this study has the pump set at 7,200 feet deep with a rod string taper consisting of 2,700 feet of .978-inch fiberglass rods, 1,750 feet of 1 inch steel sucker rods, 1,600 feet of 7/8 inch steel sucker rods, 200 feet of 1.5-inch sinker bars, and 950 feet of 7/8 inch steel sucker rods. This well has a 1.5 inch insert pump. Thermoplastic liner measuring 900 feet in length was installed below the kickoff point from 6,300 feet to 7,200 feet.

Figure 9 displays the deviation survey for Well #3 with blue representing the bare tubing section and yellow representing the lined tubing section. As can be seen by Figure 9, thermoplastic liners were installed below the kick of point and continued into the lateral section of the wellbore.

To quantify the difference between using thermoplastic liner as opposed to rod guides, two cases were calculated using a predictive program. Results from this comparison are displayed in Table 6.

Similar conclusions can be drawn as seen in the two cases compared with Well #1 data above.

Figure 10 shows the production data for Well #3. As can be seen from Figure 10, oil, water, and gas production is maintained after conversion from ESP to rod pump. Revolution Resources observed that since conversion, production has stabilized.

Well #4:

The fourth well in this study has the pump set at 7,200 feet deep with a rod string taper consisting of 2,400 feet of .978-inch fiberglass rods, 1,800 feet of 1 inch steel sucker rods, 1,600 feet of 7/8 inch steel sucker rods, 350 feet of 1.5-inch sinker bars, and 1,050 feet of 7/8 inch steel sucker rods. This well has a 1.5 inch insert pump. Thermoplastic liner measuring 1,000 feet in length was installed below the kickoff point from 6,200 feet to 7,200 feet.

According to Figure 11, gas production declined after the initial conversion. This was due to the rod pump gas locking. After two weeks of runtime, the tubing was pulled, and a velocity string gas separator was installed beneath the pump at 85 degrees to help push the gas up the annulus versus attempting to pump it up the tubing. After installing the velocity string, gas production stabilized. After these results, Revolution Resources systematically installed velocity strings below the seat nipple on higher GLR wells.

Since conversion 7.25 months ago, there has not been a failure in the system, compared to previous failure rate of 2 failures per year.

Figure 12 displays the deviation survey for Well #4 with blue representing the bare tubing section and yellow representing the lined tubing section. As can be seen by Figure 12, thermoplastic liner was installed below the kick of point and continued into the lateral section of the wellbore.

To quantify the difference between using thermoplastic liner as opposed to rod guides, two cases were calculated using a predictive program. Results from this comparison are displayed in Table 7.

Similar conclusions can be drawn as seen in the two cases compared with Well #1 data above.

FAILURE REDUCTION ANALYSIS

Table 8 shows the general failure rate analysis of Revolution Resources' field comparing rod pump with rod guides versus with thermoplastic liners.

With the 80 horizontal wells in this field, 39 wells are on rod pump with the pumps set through the curve. The initial conversions installed rod guides in the portion throughout the curve, but after modeling using predictive software and running field trials, Revolution Resources determined that running thermoplastic liners in the curve was the best practice. In the past four years, the failure rate is .68 failures/year on 20 wells with thermo plastic liners compared to 1.01 failures/year on 19 wells with rod guides, equating to a 33% improvement.

When comparing rod guides to thermoplastic liners, there is an added initial cost for the liners. On average, Revolution Resources is spending $9,175/liner/well compared to about $2,220 for rod guides through the curve. When factoring the savings from the reduction in failures, it can be estimated that the added initial cost for thermoplastic liners pays out in about 1.5 years.

For Revolution's purposes, because most wells are on the threshold between a 640-pumping unit versus a 912, they can save about $14,000 when purchasing a smaller unit due to the reduction in friction with thermoplastic liners. This offsets the cost of the liner. As commodity prices improve, Revolution Resources' plan is to convert all existing wells pumping with rod guides over to thermoplastic liners as they fail.

CONCLUSIONS

Lowering the pump into the lateral section of the wellbore increases production by increasing the drawdown of your well. Using thermoplastic liners in the curve is an economic solution to produce additional fluid out of the well offering a quick payout by maximizing reservoir drawdown and increasing production.

Installing lined tubing greatly reduces the overall system loading compared to rod guides consequently reducing failure rates and allowing for earlier conversion from ESP. Compared to rod guides, TPL reduces friction in the system, failures and OPEX as well as increases production and life of equipment.

Compared to ESPs, rod pumping with TPL can maintain and stabilize production while cutting electrical costs in more than half.

Out of 40 wells being pumped through the curve, results showed significantly lower failure numbers for TPL compared to rod guides resulting in OPEX savings from less workovers and better system efficiency.

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Type	Gearbox Loading	PPRL (lbs)	MPRL (lbs)	Polished Rod HP	Max Rod Stress	Max Side Load (lbs/25ft)	Downhole Stroke
Bare Conventional rods	110%	34709	7386	42.4	106%	664	176.1
Conventional with TPL	90%	30796	8520	31	92%	595	188.4
Continuous rod	101.5%	30948	5086	40.3	84.2%	581	178.1
Continuous rod with TPL	83%	27458	6093	30	73.6%	532	185.9
Conventional rod with rod guides	119%	36952	6749	49.4	113%	705	168.8

Table 1: Comparison of gearbox loading, PPRL, MPRL, polished rod horsepower, maximum rod load, maximum side load and downhole stroke for conventional rods, continuous rods, conventional rods withTPL, continuous rod with TPL, and conventional rod with rod guides.

Type	L (ft)	W_r (lb/ft)	$W_{segment}$ (lb)	F_N (lbf)	$f_{friction}$	F_D (lbf)
Bare Conventional rods	25	2.224	55.6	36.31	0.2	-7.26
Conventional with TPL	25	2.224	55.6	36.31	0.1	-3.63
Conventional rod with rod guides	25	2.224	55.6	36.31	0.25	-9.08
Continuous rod	25	2.04	51	33.31	0.2	-6.66
Continuous rod with TPL	25	2.04	51	33.31	0.1	-3.33

Table 2: Comparison of normal force, friction coefficient and drag force for conventional rods, continuous rods, conventional rods with TPL, continuous rod with TPL and conventional rod with rod guides.

SURVEY DATA WELL #1										
MD (ft)	**Incl (°)**	**Azm (°)**	**TVD (ftKB)**	**VS (ft)**	**NS (ft)**	**EW (ft)**	**DLS (°/100ft)**	**Build (°/100ft)**	**Turn (°/100ft)**	**Unwrap Displace(ft)**
6,993.00	**82.98**	**179.99**	**6,686.37**	**225.73**	**-190.49**	**-402.02**	**6.42**	**6.36**	**-0.91**	**1,083.27**
7,088.00	**85.72**	**180.39**	**6,695.72**	**319.00**	**-285.02**	**-402.34**	**2.91**	**2.88**	**0.42**	**1,177.80**

7,183.00	**88.31**	**180.47**	**6,700.67**	**414.45**	**-379.88**	**-403.05**	**2.73**	**2.73**	**0.08**	**1,272.66**

Table 3: Deviation Survey for pump depth point in Well #1.

Well # 1 Rodstar Comparison		
	Liner	Rod Guides
PPRL	31235	33025
MPRL	5859	5218
SPM	5.85	5.87
Downhole stroke	157.8	139.3
GB Loading	93.3	110.7
PU Loading	73	77
Monthly Electric	2012	2273
Production	283	280
Amended Production (Takacs)	281	248
Peak Rod Loading	74	80

Table 4: Predictive Software comparison of key performance indicators when using liners versus rod guides.

Well # 2 Rodstar Comparison		
	Liner	Rod Guides
PPRL	24233	25218
MPRL	6814	5856
SPM	6.47	6.52
Downhole stroke	131.7	121.4
GB Loading	85	91
PU Loading	79	83
Monthly Electric	1137	1283
Production	193	194
Amended Production (Takacs)	190	176
Peak Rod Loading	57	62

Table 5: Predictive Software comparison of key performance indicators when using liners versus rod guides for Well #2.

Well # 3 Rodstar Comparison		
	Liner	Rod Guides
PPRL	21932	22922
MPRL	7118	6570
SPM	4.06	4.18
Downhole stroke	82.4	70.8
GB Loading	75	78
PU Loading	60	63
Monthly Electric	512	554
Production	71	70
Amended Production (Takacs)	75	66

Peak Rod Loading	93	100

Table 6: Predictive Software comparison of key performance indicators when using liners versus rod guides for Well #3.

Well # 4 Rodstar Comparison		
	Liner	Rod Guides
PPRL	21023	21918
MPRL	8166	7364
SPM	5	5
Downhole stroke	99.7	96.1
GB Loading	77	81.7
PU Loading	69	72
Monthly Electric	620	675
Production	110	106
Amended Production (Takacs)	111	107
Peak Rod Loading	66.5	73.4

Table 7: Predictive Software comparison of key performance indicators when using liners versus rod guides for Well #4.

Category	Well Count	Avg Years	Failures/Year
Thermoplastic Liners	20	3.26	0.68
Rod Guides	19	3.89	1.01

Table 8: General results for Thermoplastic liner failure rate analysis when compared to rod guides

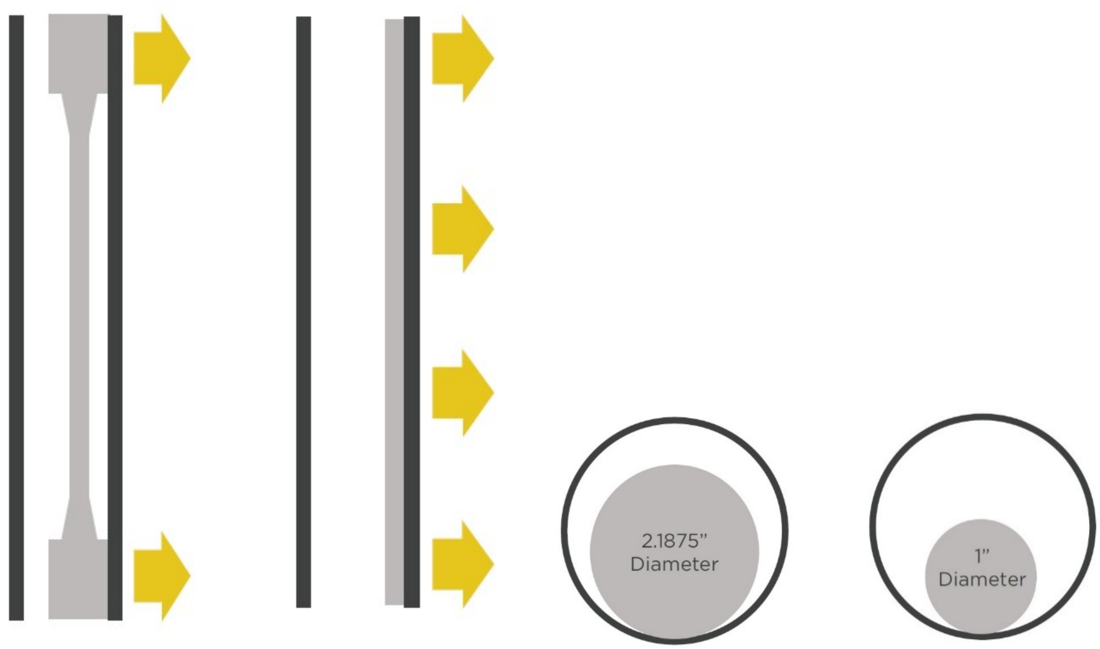

Figure 1: Pressure exerted on tubing from conventional rod compared to continuous rod (left), difference in flow area of conventional rod string with couplings and continuous rod (right).

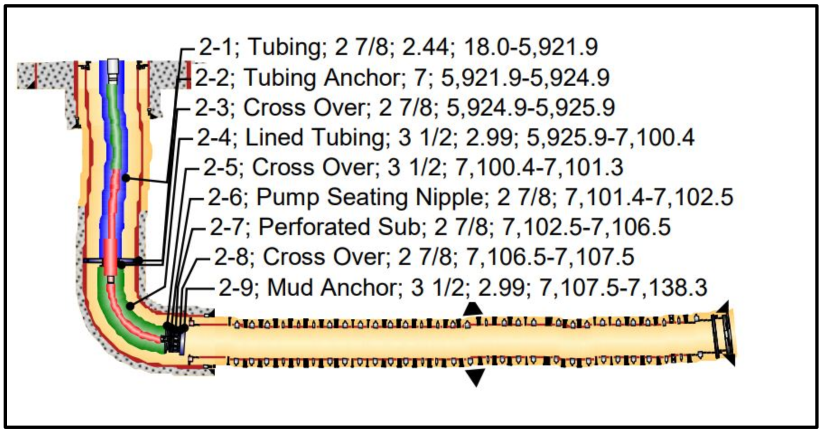

Figure 2: Typical bottom hole assembly for Revolution Resources case study

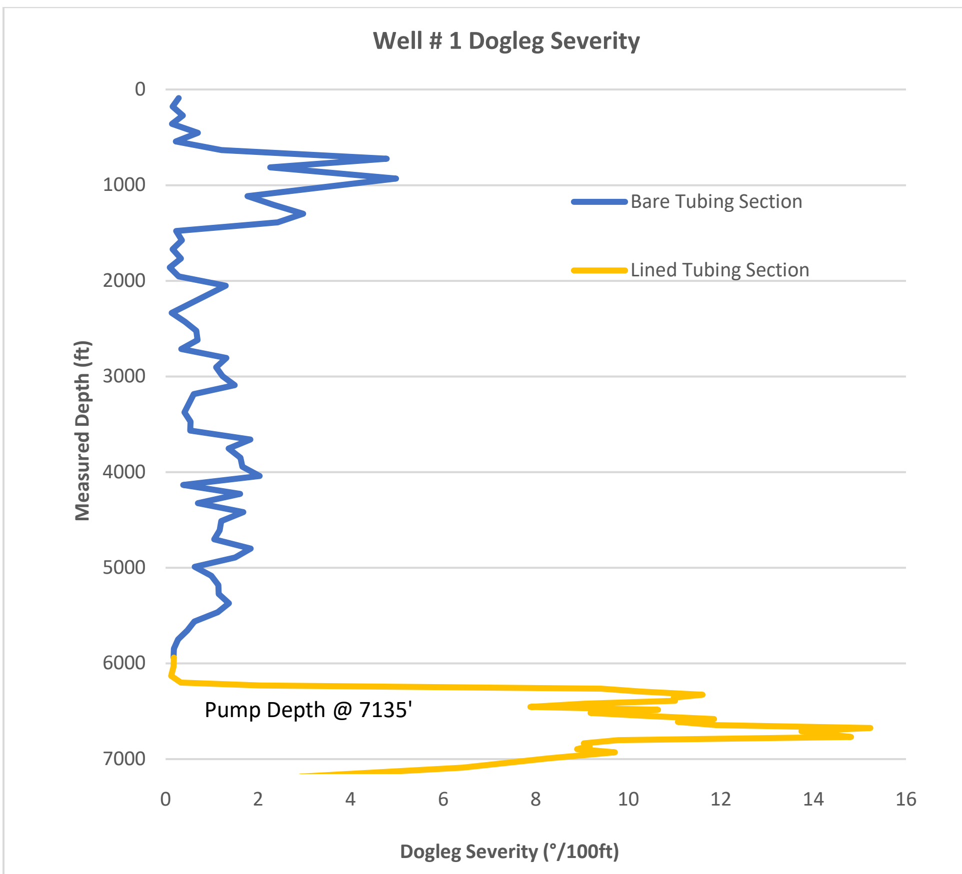

Figure 3: Dogleg severity graph for Well #1.

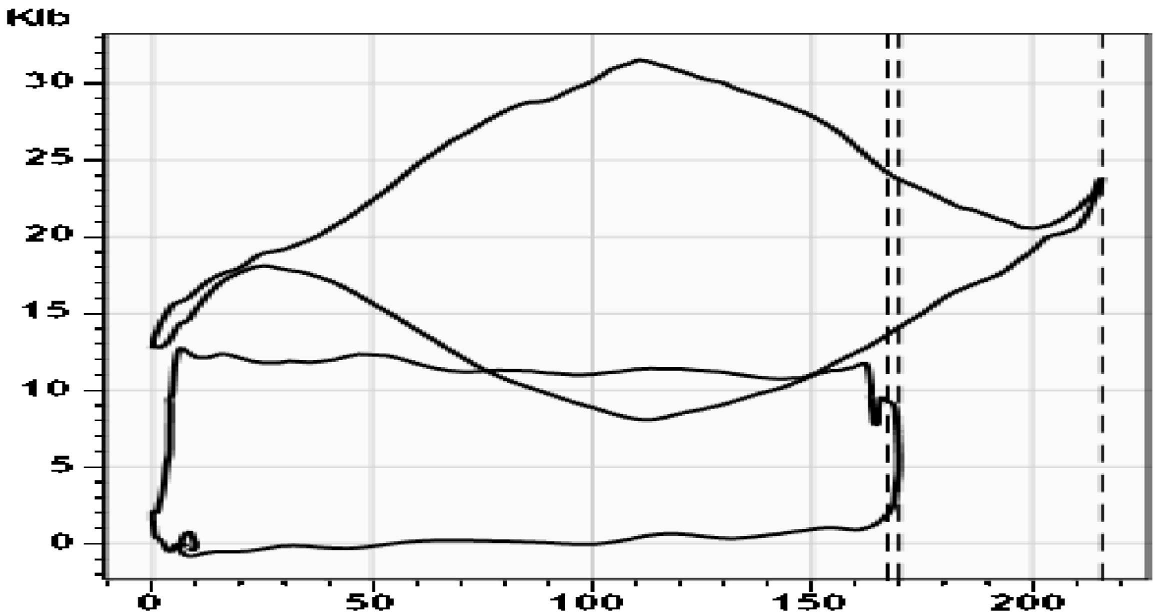

Figure 4: Well #1 Downhole Pump Card

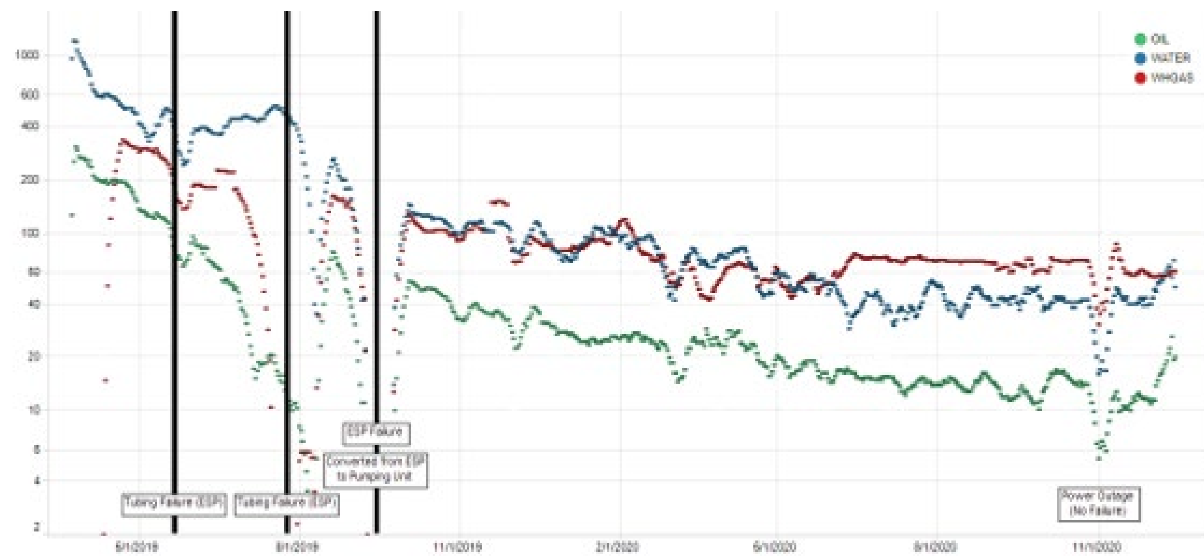

Figure 5: Production data from Well #1 before and after conversion from ESP to rod pump with thermoplastic liner.

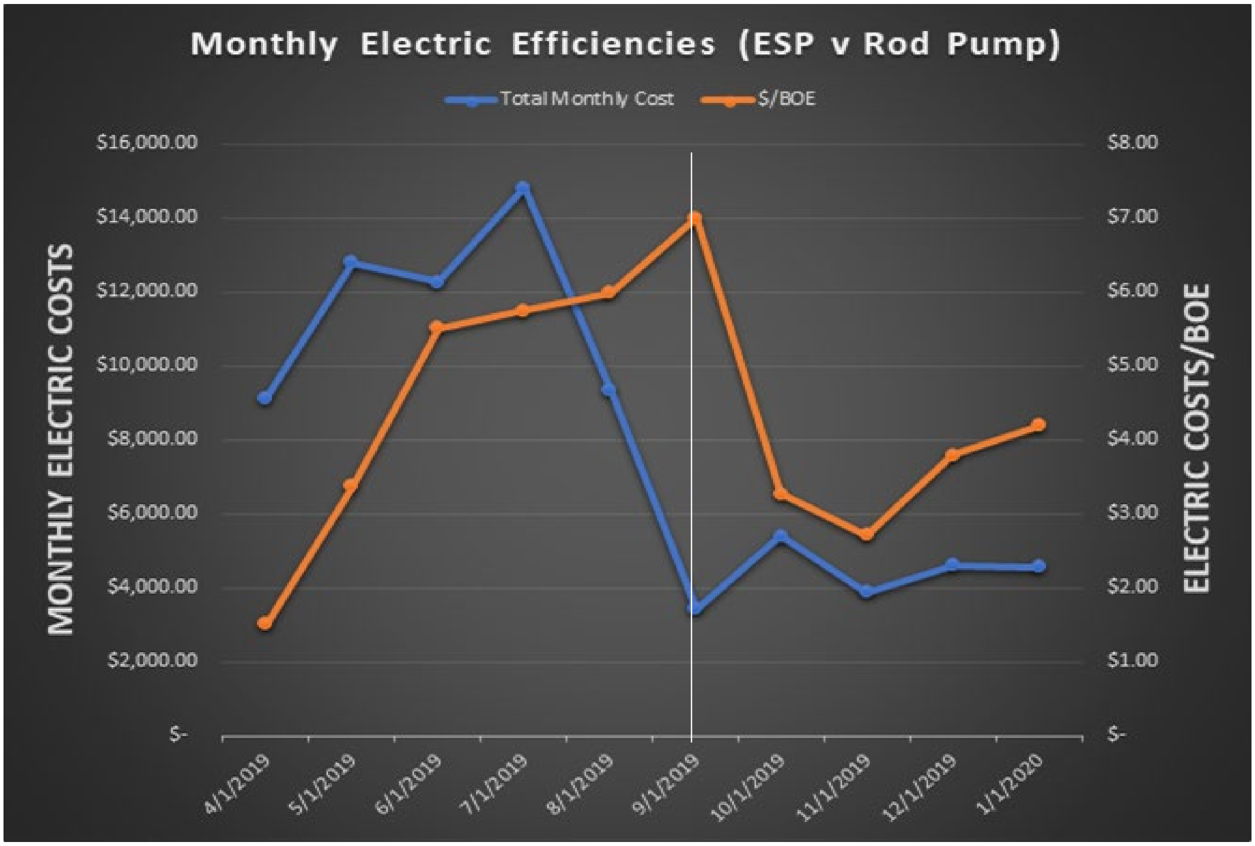

Figure 6: Graph of Electrical Savings after conversion from ESP to rod pump with thermoplastic liner.

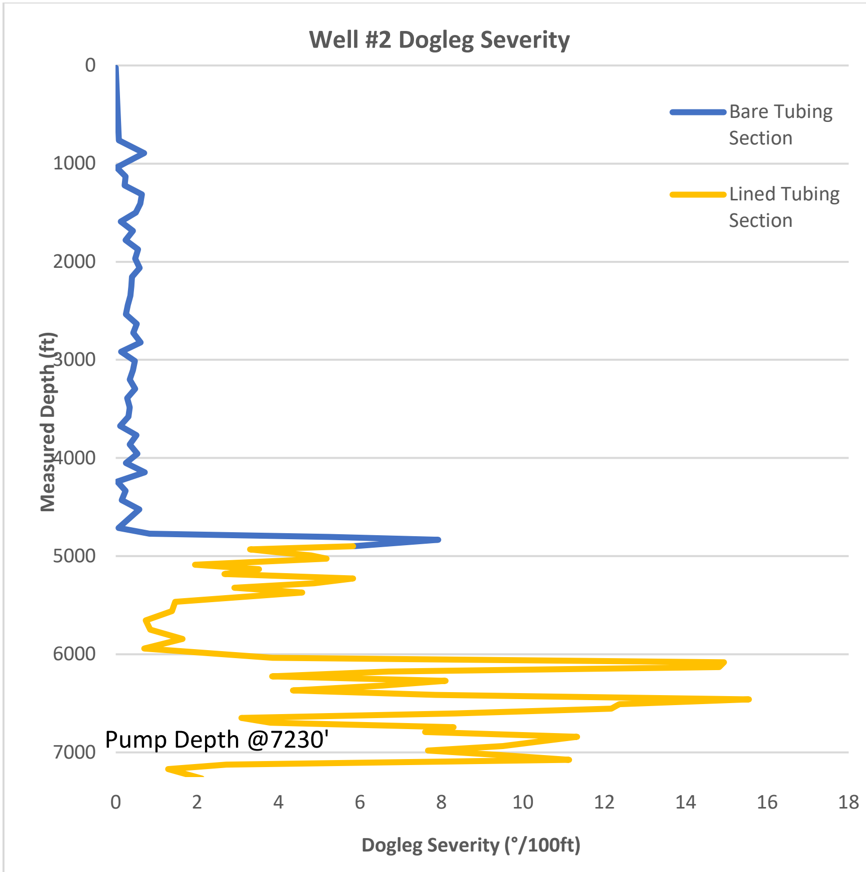

Figure 7: Dogleg severity graph for Well #2.

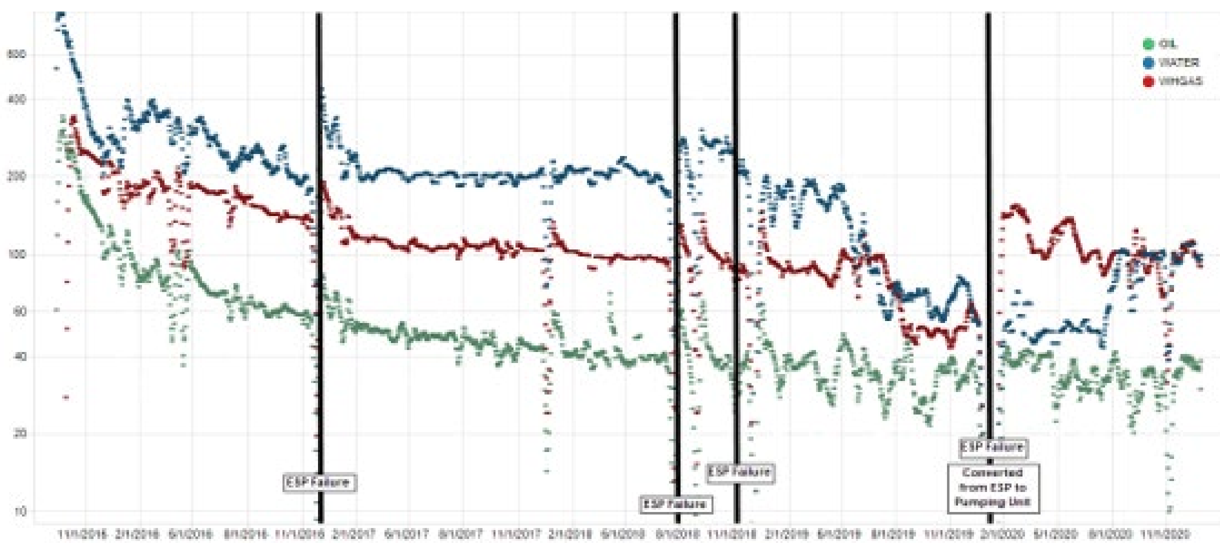

Figure 8: Production data from Well #2 before and after conversion from ESP to rod pump with thermoplastic liner.

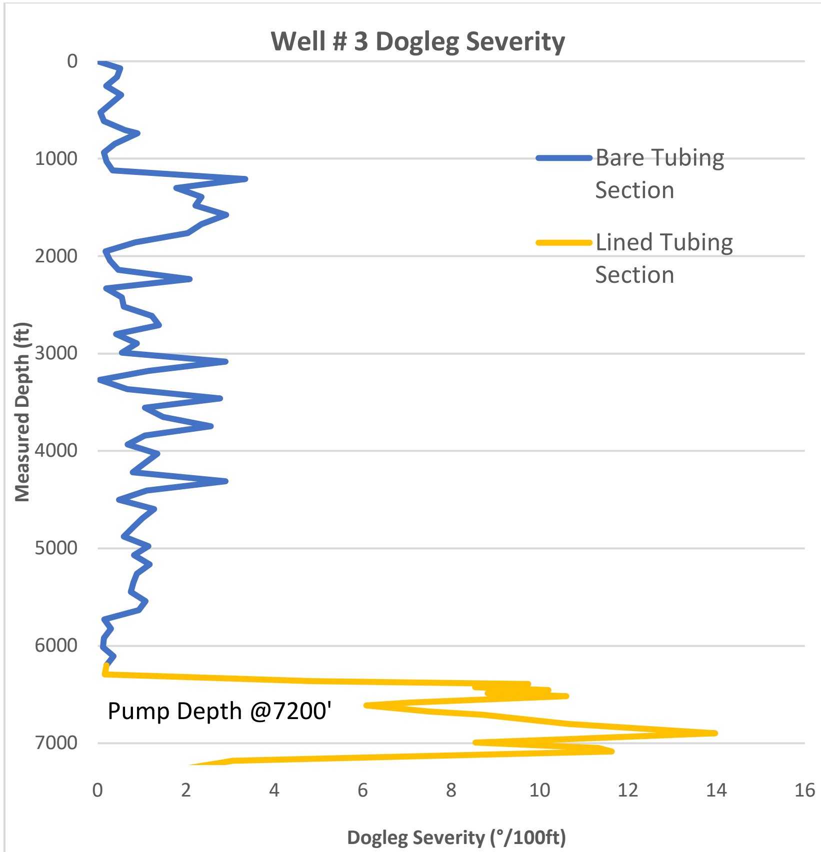

Figure 9: Dogleg severity graph for Well #3.

Figure 10: Production data from Well #3 before and after conversion from ESP to rod pump with thermoplastic liner.

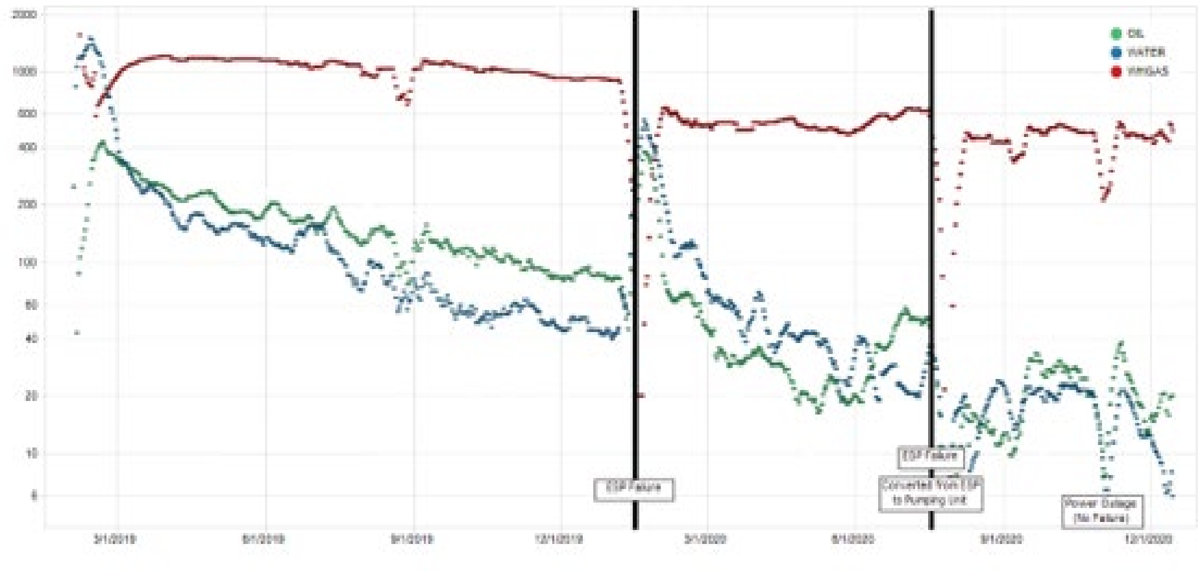

Figure 11: Production graph before and after conversion for Well # 4.

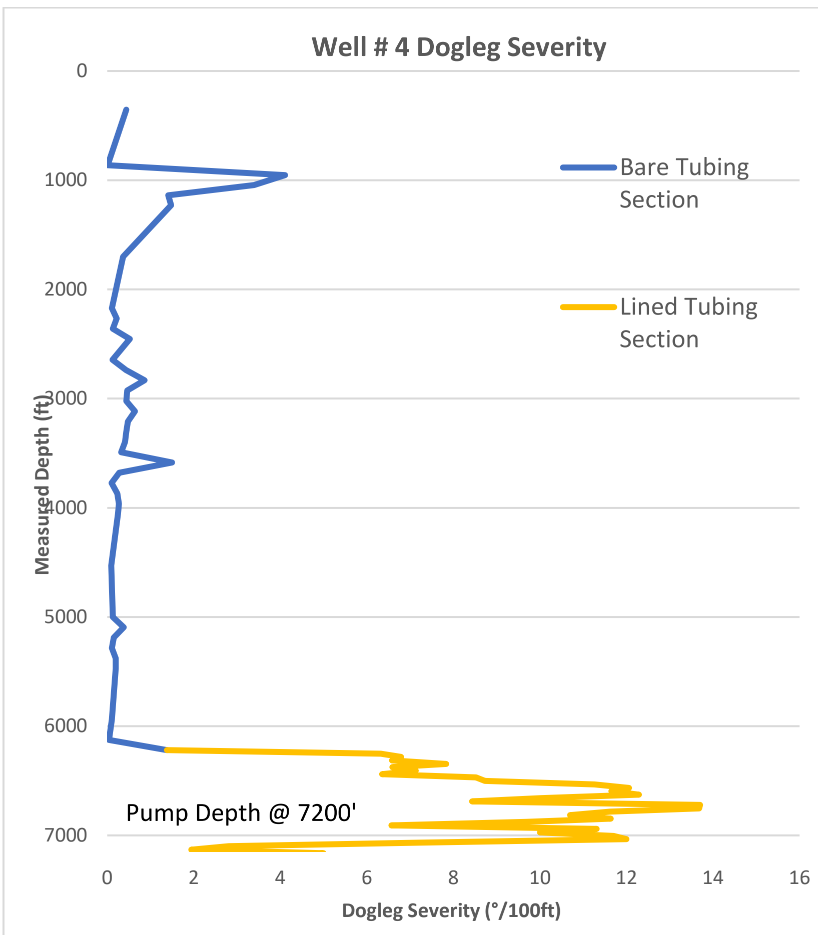

Figure 12: Dogleg severity graph for Well # 4